RESERVOIR SOLUTIONS

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Industry to SEC: Require proved only, change one-day price

The oil and gas industry recommended that the U.S. Securities and Exchange Commission modernize its 1978 petroleum reserves reporting rules and take a principles-based approach, primarily relying on the 2007 Society of Petroleum Engineers Petroleum Reserves Management System. Industry also asked the commission to establish and confer with an independent board of technical experts.

The SEC received 78 comments on its concept document by the Feb. 19 deadline. Twenty-two public oil and gas companies opined on reporting regulations. Joining them were consultants, accountants, associations, government agencies and others, including a California English professor and a "think tank" from the Massachusetts Institute of Technology.

On the final five days of the 60-day comment period, 21 O&G companies made recommendations. Four of those—BP, Exxon Mobil Corp., Shell Oil Co. and Devon Energy Co.—besides individually commenting, joined seven other companies—international operating companies and large independents—to comment through the American Petroleum Institute.

Under the rulemaking process, the next step is for the SEC to file a proposal for new rules with a 60-day comment period. After review, the SEC then publishes final rules with another 60-day comment period. Then the commissioners vote on whether to adopt the final regulations.

Before first production, PUD reserves from deepwater GOM fields, such as Marco Polo (pictured), typically are reported to the SEC based on various analyses without the requirement for flow testing. Respondents asked the SEC to extend that deepwater GOM standard to potential areas worldwide.

"It is unlikely the SEC opened this process unless it intended to make changes to the rule. Depending on how quickly the SEC publishes a rule proposal, it is conceivable that we could see a new disclosure rule by late summer," said **David Curtiss**, director of the American Association of Petroleum Geologists Office of Geoscience and Energy in Washington, D.C.

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Inside Reservoir Solutions newsletter

Special: Public comments to the U.S. SEC

Concepts—Cont. from Page 1

O&G companies, for the most part but with exceptions, asked the SEC to consider the following "concepts" for disclosure:

- Report probable reserves as option; require only proved reserves.
- Use SPE-PRMS in a principles-based approach.
- Use historical average sales price with option for economic sensitivities.
- Keep using "existing operating conditions" in principle.
- Treat mined reserves from unconventional resources as reserves under SPE-PRMS.
- Use "reasonably certain" standard to book proved undeveloped reserves farther than one offset from a commercial well.
- Use third-party reserves auditors as option, not requirement.
- Use current technology proven in a region to validate reserves.

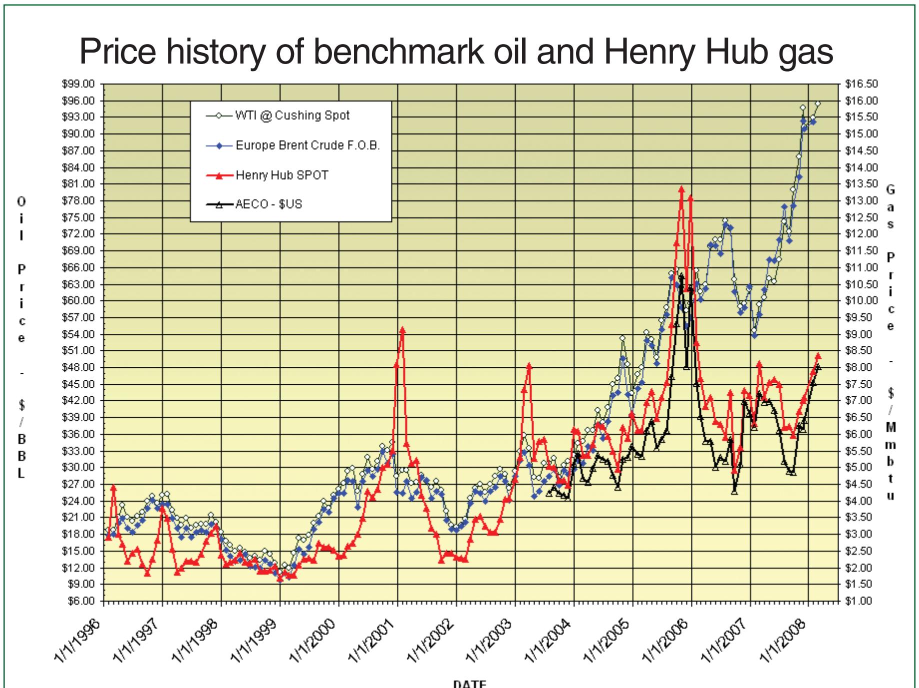
Proven technology

Comments generally called for the SEC to widen its acceptance of 3D seismic surveys, wireline formation testing and analogy. Public issuers use a combination of those procedures along with openhole well logs, cores and well tests to justify proved reserves filings.

A flow test to the surface is considered by the commission to be the only "conclusive formation test" for justifying proved reserves except in the deepwater Gulf of Mexico, where flow testing may not be required. The SEC allows producers there to use a combination of technologies to justify PUD bookings. Respondents asked the SEC to expand that standard to other producing regions, not just the deepwater GOM.

To help justify and plan capital-intensive E&P projects, oil and gas companies routinely rely on seismic and other methods besides flow tests. Likewise, they are asking the SEC to accept those technologies in support of their reserves filings.

About 20 percent of bitumen produced in the Canada oil sands is mined and companies want the SEC to consider production from that extraction method to be oil reserves. The commission currently allows the other 80 percent, produced in situ, to be reported as reserves. Bitumen from this Petro-Canada oil sands mining operation is reported under reserves definitions for minerals.



The historical price chart shows published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

Publisher's Statement
Reservoir Solutions newsletter is published quarterly by Ryder Scott Company LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of studies a year. Ryder Scott multidisciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 115 employees, including 80 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

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Based on a 4D seismic survey, infill wells drilled in the Andrew field (platform shown) in the U.K. North Sea proved to be successful. Industry has asked the SEC to give more weight to seismic analysis used with other data to justify reserves for undrilled, planned locations.

Companies also called for the SEC to consider the successful track record of production and completion technologies, such as horizontal drilling and fracture stimulation techniques in the U.S. tight gas plays. Most respondents asked the SEC to use the SPE-PRMS in a principles-based approach to considering technology while rejecting a rules-based, cookie-cutter approach.

Respondents also wanted the SEC to establish an ongoing review process to consider technology and issue periodic guidelines. Chesapeake Energy Corp. commented, "Let the cumulative evidence speak for itself without excluding a particular technology simply because it was developed, tested and shown to be accurate after the issuance of the latest rules."

Bob Wagner, a former senior vice president at Ryder Scott, made the case that O&G companies would have to present documented, compelling cases on deployed technology. He said, "Any technology that has been field tested and has shown consistency and repeatability in a given area may qualify as acceptable technology. Each company bears the burden of proof to show that a technology should be accepted as proven in a given region."

More faith in seismic

SEC staff guidance in 2000 stated that "seismic data is not an indicator of continuity of production and therefore cannot be the sole indicator of additional proved reserves." Ultra Petroleum Corp., the smallest E&P company commenting, shared a different view in its comment letter.

"For our major asset, we have used our 3D interpretation for the past seven years, drilling a mixture of PUD, probable, possible and even un-engineered locations with 100 percent success in obtaining commercial wells," the company stated.

Chinese national oil company CNOOC Ltd. asked the SEC for more latitude in accepting seismic analysis for determining hydrocarbon contacts. "When the flat points of gas field seismic data are proved by drilling to be the influence of the gas-oil contact, the corresponding depth of seismic flat points could be interpreted as gas-oil contacts and the proved reserves are estimated accordingly," the Beijing-based company said.

Fluid contacts and technology

Shell International B.V. asked the SEC to expand its acceptance of fluid pressure and density measurements in wells to support reserves estimates. The company commented that the method "provides data for a high-confidence calculation of the point of hydrocarbon-water contact. Yet this method of defining the extent of hydrocarbon presence for determination of proved reserves is not allowed. This ruling should be reconsidered."

BP Plc referred to the SEC's "limiting guidance on the use of hydrostatic pressure measurements in contact definition." The current SEC interpretation is that in the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons should be used. While supporting that, BP stated that "if pressure-and-fluid and seismic data that have been shown to be good indicators of contact depth in appropriate analogs are available, and the evaluator can demonstrate reasonable certainty of their estimate, then that information should be used."

Please see Contacts on next page

Producers say that pressure communication between wells is difficult to establish in areas like the Fayettville shale (wellsite shown) with "continuous" low-permeability gas reservoirs. They asked the SEC to consider other data in unconventional gas plays. Photo courtesy Perkins & Trotter PLLC.

Contacts—Cont. from Page 3

CNOOC asked the SEC to consider seismic, wireline logging and other techniques in combination "to determine oil, gas and water contacts and oil- and gas-bearing ranges." The company said, "On the basis of reliable pressure data in some thick reservoirs, when the free water level in existing reservoirs and favorable fluid quality are determined, the proved reserves estimated by determining fluid contacts with pressure data should be adopted."

A subcommittee of the SPE Oil and Gas Reserves Committee is drafting guidelines for the PRMS that will include the use of pressure- and fluid-gradient data to estimate contacts, said the AAPG.

Pressure communication, seismic and offsets

Establishing pressure communication between wells in low-permeability unconventional gas formations is problematic. The SEC, however, requires pressure communication to meet a high-level "certainty" criterion for proving "continuity of production from the existing productive formation" and booking undrilled PUD locations greater than one offset location from a producing well.

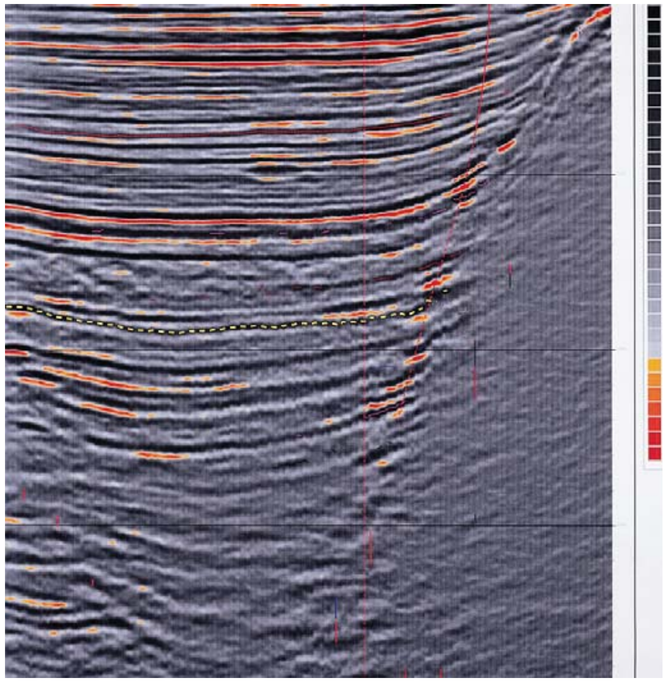
Devon commented that unconventional reservoirs—such as coalbed methane, shale gas and oil sands—that sometimes cover large areas are not "amenable to the proof required of pressure communication." The company continued, "…seismic data, when calibrated with well data, leads to reasonably certain estimates of proved reserves more than one location away. Therefore, these types of reservoirs are reasonably certain of production when drilled. Accordingly, the concept of 'certainty' with respect to proved undeveloped locations more than one offset away from a producing location should be revised to that of 'reasonably certain' of production."

"…the value for those non-proved reserves is evidenced by what companies are paying for them in acquisitions."

Companies have questioned the SEC's "certainty" threshold and the implication that it means "absolute certainty." At the same time, the SEC has a lower-level standard of "reasonably certain" for future production from offsets one location from the producer. Companies want the "reasonably certain" standard to apply to all offsets whether contiguous or not. That would give the SEC greater flexibility to consider the use of well control and seismic analysis for justifying outlying PUD locations.

Southwestern Energy Production Co. acknowledged that recent technological advancements used in unconventional resource reservoirs fall short of establishing absolute certainty. However, the company said that those technologies, especially as they are used in the laterally continuous, gas-bearing Fayetteville shale, provide enough assurances to satisfy disclosure requirements.

Chesapeake said that unconventional gas reserves



Based on strong amplitude anomalies in this seismic profile, the company identified several drilling targets and penetrated more than 20 pay zones. Companies agreed with the SEC that relying on geophysical interpretation alone leads to misinterpretations, but asked the commission to be more flexible in considering the use of seismic with well data.

often are in continuous reservoirs and asked the SEC to revise its rule on offsets and PUD reserves. "Significant reserves of natural gas are not captured in the commission's current definition of proved reserves," the company commented, adding that the value for those non-proved reserves is evidenced by what companies are paying for them in acquisitions.

Fred Ziehe, managing senior vice president at Ryder Scott, commented that the certainty criterion for PUDs greater than one location away is appropriate in cases where minimal or no well control exists. That certainty level can be met with pressure data or well log data indicating changes in fluid levels (which infer changes in pressure), he said.

However, Ziehe stated that the SEC certainty standard is too stringent, in some cases, where well control is present but pressure data is not available to prove certainty. "In certain instances, a detailed geological analysis of well control in highly developed reservoirs, with close spacing of existing wells, can be used to reach a level of reasonable certainty of production when drilled," Ziehe remarked.

Other offset issues

Denbury Resources Inc. commented that closer well spacing reduces the acreage of offset locations previously considered as PUDs and therefore reduces the associated reserves. Ultra also questioned the SEC on that issue, saying, "If PUD locations are booked as direct offsets to a 40-acre drilled producing well and the area is downspaced to 10-acre drilling, do we lose PUD locations? Denbury recommended that if a PUD location meets the SEC definition of such at any time, the location should not be subject to a revised one offset definition.

Based on its experience with horizontal wells producing from the Fayetteville shale, Southwestern commented that the SEC should require that offsetting wells have similar lateral length without regard to direction of the lateral. The company said that its data indicates that productivity of the horizontal well across the length of its lateral can be demonstrated by the following:

- Multi-stage hydraulic stimulations distributed throughout the horizontal lateral from where the lateral first penetrates the reservoir to the end of the lateral
- Production logs run on horizontal producing wells
- Microseismic data from the multi-stage hydraulic stimulations to the extent it shows a consistent pattern that these stimulations can treat the entire horizontal lateral length
- Openhole porosity and resistivity logs run on horizontal wells that indicate the entire lateral length is contributing gas production

EOR and analogs

The SEC requires a response in a reservoir from enhanced oil recovery before incremental proved reserves can be reported. BP commented that "as secondary and tertiary recovery projects become more commonplace, it makes sense to not limit proved reserves to primary depletion prior to response in a reservoir if an adequate track record in appropriately chosen analogs and support by geologic and engineering data are available."

Denbury also agreed, saying, "The commission should consider excluding the requirement of a production response in the case of the more widely applied enhanced oil recovery techniques, such as water flooding and CO_2 flooding that have been proved with reasonable certainty to recover additional quantities of oil."

The company also asked the SEC to reconsider its definition for booking proved reserves from EOR projects based on analogy. Under SEC guidelines, the subject field for planned EOR has to have reservoir properties—such as permeability, porosity and saturations—that are equal to or better than the characteristics of the nearby analog producing from EOR. Both subject and analog fields have to produce from the same reservoir and have comparable development schemes.

Denbury said that knowledge gained over the past 30 years since the SEC issued its rules has enabled reserves evaluators to estimate reserves with reasonable certainty in future EOR projects that do not meet the SEC's analogy definition.

Proved only

Status quo was also a rallying cry. For the most part, public oil and gas companies supported the commission rule to limit required disclosures to proved reserves despite widespread criticism that reporting proved only undervalues companies and misleads investors. They cited the SPE-PRMS most often as the model for reserves classifications and their certainty levels.

While commenting that 2P reserves "could be viewed as misinformation and misleading to investors," Shell said, "Proved reserves, in the context of a higher level of confidence that they will ultimately be produced, are more aligned with metrics of revenues, income, profitability and cash flows that investors are most focused on."

Petrobras, an NOC in Brazil, had a different view, saying, "The disclosure of non-proved reserves allows the investor to have a more complete view of the asset evaluation since there are investments and future expenditures associated with these volumes."

While 18 of 19 companies stopped short of asking for mandated 2P reporting, most supported the option to report 2P reserves at a minimum. In the end, though, most companies subscribed to the "less is best" approach, saying a proved-reserves-only reporting system has fewer bureaucratic entanglements and lessens legal exposure. Currently, O&G companies confine the publishing of non-proved reserves to management discussions and press releases.

API, representing "big oil," commented, "We believe that investors, other financial statement users and registrants would not be well served by the mandated inclusion of probable reserves or other reserve/resource categories below the proved threshold due to the increased uncertainty of resources in these categories and the breadth of methodologies and evaluation techniques that may be employed in their calculation. It is also felt that the reporting of reserve/resource categories below the proved threshold could expose companies to additional, unwarranted litigation due to the increased risk and uncertainty associated with these resources."

Other concerns in reporting reserves past proved focused on tax liabilities. **Dan Olds**, senior vice president at Ryder Scott, said that producers are concerned that any recognition of non-proved reserves would result in attempts by local taxing authorities to assess ad valorem taxes on the non-proved reserves. "This is a legitimate concern, as it would be difficult to ensure

Please see 2P reporting on next page

2P reporting—Cont. from Page 5

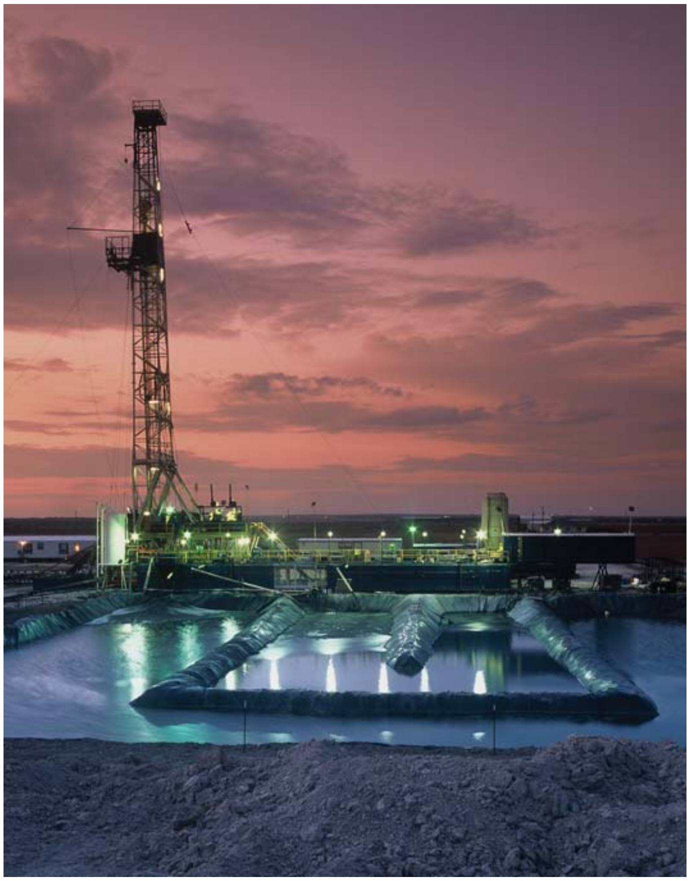
uniform and equitable taxation, particularly if the disclosure of non-proved reserves was discretionary," he added.

Calgary-based Talisman Energy Inc. was the only commenting O&G company calling for the required reporting of proved and probable reserves. The company said, "In our view, probable reserves are material to the valuation of most oil and gas companies, and is the reason why Talisman discloses probable reserves."

PUD vintaging

The SPE-PRMS states if reserves remain undeveloped beyond a reasonable timeframe or because of repeated postponements, reasons for the delay should be documented to justify retaining these quantities. The SPE-PRMS adds that "while there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than 5 years." Most respondents recommended that the SEC adopt this guideline with special emphasis on the exception to the five-year limit.

Major companies, through API, took a stronger stand against time limits, asking the SEC to "avoid the use of arbitrary time deadlines as this would be inconsistent with a principles-based regime." The API working group continued, "Arbitrary deadlines could lead to situations where undeveloped reserves were debooked merely because of the passage of time and not because of any fundamental change in the geoscience, economic or operating assessment of reserves viability or management commitment to develop the reserves."



In the strongest response to the PUD vintaging issue, BP said, "There should be no specific time set for the development of proved reserves. The volumes must meet all of the requirements of geologic, engineering and commercial data, and an appropriate activity plan must be presented for the volumes to ensure that there is commitment to develop. However, this plan could cover a time span of many decades as in the case of large LNG projects."

BHP Billiton Petroleum said that the SEC should consider a longer time frame where the producer defers development of economic projects for market-related reasons or to meet contractual or strategic objectives and clearly documents those justifications.

No more single-day pricing

No respondents supported the SEC's current single-day pricing rule for reporting. Most companies urged the SEC to use a 12-month historical average sales price to eliminate the volatility created when using single-day prices. For a U.S. company with a calendar fiscal year, the trailing 12-month period would run from Oct. 1 of the previous year to Sept. 30 of the reporting year to provide ample time for companies to begin preparing year-end reserves estimates.

Three O&G companies—Apache Corp., Southwestern and Chesapeake—joined by the MIT Center for Energy and Environmental Policy Research called for the use of average futures pricing. The comment letter from Chesapeake asked the SEC to adopt an average of 12-month futures strip prices. "Commodity markets have changed dramatically with deregulation of the industry, and buyers and sellers of oil and natural gas now have the opportunity and ability to lock into long-term pricing. Forward-looking prices should more accurately reflect the price to be received, at least during the first year of production of proved reserves, than an historical price," the company commented.

Chesapeake also said a 12-month strip would smooth out daily price volatility and mitigate the potential for reserves writedowns caused by short-term price fluctuations. Southwestern said, "We believe that an average of futures pricing, including the effect of existing hedges, is more representative of current market conditions and that such average pricing should be specifically required by the Commission to ensure consistency among reporting companies." Apache said that a forward-looking average of futures prices is customary in valuing reserves acquisitions.

In a detailed 10-page response, MIT said that although average historical price eliminates short-term volatilities in oil and gas prices, it does not account for long-term volatility, such as the price increase of the last few years, which "many people" believe is a permanent change in fundamentals. MIT researchers cited their 2005 study that showed that a 17-month futures price is immune to more than 90 percent of the short-term volatility while capturing all of the fundamental volatility.

Advisory board

In response as to whether the SEC should look to any professional organizations to set and enforce adherence to standards, the API working group of companies recommended that the SPE OGRC be "the responsible party to maintain and update the PRMS with appropriate SEC oversight and representation. This approach would be similar to how the commission works with the Financial Accounting Standards Board to establish and maintain financial accounting standards."

Devon, which participated with the API group, said that a better solution than the OGRC would be to model an independent body of technical experts after the FASB. "The OGRC is a volunteer group that reports to the SPE Board, and obtaining a quorum of the committee can be difficult. This would not be satisfactory in cases where the SEC staff needed advice in a timely fashion," commented Devon.

The company continued, "This 'Reserves Accounting Standards Board' could be funded by industry both for administrative costs and for personnel."

"Requiring companies to engage third parties will also raise the question as to the qualifications of the third-party…,"

"Similar to the FASB, a select group of experts in reserves estimation could be seconded by a variety of companies for a set term; three years is recommended as a minimum. The experts would serve full time with RASB and work with industry and the SEC to continually update the reserves framework and consult on various issues with the SEC staff." Chesapeake commented that the OGRC is comprised of industry professionals with other employment obligations and may not be the best option for a standard-setting body.

No required third-parties

O&G companies agreed that they did not want the SEC to require third-party audits of reserves. The most cited reason was that company staffs have more day-to-day knowledge of properties while qualified consultants do not have the manpower to handle additional government-mandated work within a compressed timeframe.

Sasol Ltd. commented that "there is presently a dearth of qualified professionals able to carry out resource estimation, a situation which will only worsen… To add to the work burden by requiring additional work by a limited number of professionals will only result in a lower standard of study by the industry. Requiring companies to engage third parties will also raise the question as to the qualifications of the third-party…,"

Petrobras stopped short of calling for required third-party certification while calling it a "very positive contribution" and suggesting "that the certification should be periodic and include the principal assets of the company."

While generally against a requirement, Nexen Inc., a Calgary-based company, suggested that some companies may not be large or complex enough to assign segregated duties and processes to enhance the "quality of the estimates." Nexen cited the Canada National Instrument 51-101 requirement for third-party estimates as a possible approach.

Calgary-based Encana Corp. was the only O&G company with a blanket recommendation that the SEC require the use of outside reserves auditors. "Credible reserves are a cornerstone of a company engaged in oil and gas exploration, development and production activities. Independent evaluators are uniquely positioned to provide an 'arms length' appraisal…," the company commented.

Probabilistic analysis

A handful of consultants recommended that the SEC replace its "reasonable certainty" concept used in a deterministic approach and consider statistical approaches to eliminate evaluator bias. They referred to SPE-PRMS definitions on probabilistic analysis as a model, albeit in a limited capacity. The system, approved by industry professional societies, received criticism for not supporting aggregation at the portfolio level.

A few O&G companies referred to P90, P50 and P10 estimates to assess project design, implementation and costs. They also asked for increased SEC recognition of probabilistic analysis but were not as detailed in their recommendations as the consultants.

Editor's Note: It is not the intention of this summary, which contains excerpted material, to fully represent the positions of cited companies within the full context of their public comments. For a complete review of all posted comments, go to http://www.sec.gov/comments/s7-29-07/s72907.shtml.

Two engineers promoted to lead RS Canada and Denver

Ryder Scott has promoted two petroleum engineers to lead the Ryder Scott Calgary and Denver offices. **Howard Lam** was promoted to managing senior vice president in charge of Calgary operations. **Jim Baird**, vice president, was promoted to manager at the Denver office replacing **Larry Nelms**, who continues as managing senior vice president and board member.


Lam

Lam has more than 30 years experience in the oil and gas industry, primarily in reservoir engineering and management and in reserves evaluation.

Before joining Ryder Scott 10 years ago, Lam was a manager at Pembina Corp. for 15 years. He also worked at Husky Oil Operations Ltd. and Esso Resources Canada Ltd. as a petroleum engineer and group leader.

He has a B.Eng. degree, cum laude, in chemical engineering from McGill University and an M.A.Sc. degree in chemical engineering from the University of British Columbia. Lam is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA), Society of Petroleum Engineers (SPE) and Petroleum Society Canadian Institute of Mining and Metallurgy (CIM).


Baird

Baird, who joined the Ryder Scott Denver office in 2006, has more than 37 years of diverse oil and gas experience, including reservoir management, reservoir simulation, and reserves evaluation. Geographic areas of expertise include northern Rocky Mountains; Uinta, Paradox and San Juan basins and Mid-Continent and U.S. gulf coast areas.

Baird was a manager for the Rocky Mountain region reservoir engineering group at Questar Exploration & Production Co. during 1999 to 2006. He was chief engineer at Celsius Energy Co. from 1986 to 1999 where he prepared quarterly and annual reserves reports.

Baird began his career at Gulf Oil Corp. in 1970 as a production engineer. He has a BS degree in petroleum engineering from the University of Missouri at Rolla.


Guale Ramirez, front row, second from left, international group leader at RS, hosted a party for China National Offshore Operating Co. Attendees included, back row, from left, Wu Xingru, Song Gang, Ge Zunzeng, Zhou Fang, Sun Pengxiao, Li Xiangyang, Li Mao, Chi Shugen, Olga Basanko (RS petroleum engineer) and Harris Ghozali (RS project coordinator for CNOOC); Middle row, from left, Cao Yue (RS technician), Sun Yingtao, Cai Hua, Wang Fengrong, Liu Shuangqi, Yan Weige, Shen Yuling, Helen Ghozali (spouse of H. Ghozali); Front row, from left, Sun Bingyi (CNOOC director of oil and gas reserves), Ramirez and spouse Becky Ramirez.

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